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Biomass-Fired Cogeneration Project: Best Available Control Technology Analysis for Greenhouse Gases

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1 Introduction

Sierra Pacific Industries, Inc. (SPI) owns and operates an existing lumber manufacturing facility located in Anderson, California, and proposes to construct and operate a cogeneration unit at that facility. The boiler associated with the proposed cogeneration unit will be designed to burn biomass fuel to produce approximately 250,000 pounds of steam per hour. SPI submitted a PSD permit application to USEPA Region 9 and Shasta County Air Quality Management District (SCAQMD) in March 2010 that included BACT analyses for all criteria pollutants expected to increase by more than the PSD Significant Emission Rates (SERs), as well as pollutants exceeding the emission rate thresholds in SCAQMD Rule 2:1, Part 301. The intent of this report is to supplement the permit application by providing an analysis of BACT for GHG emissions from the proposed project.

On May 13, 2010, USEPA issued the final "Tailoring Rule" with a stated intent to establish a "common sense approach" to addressing greenhouse gas emissions from stationary sources, by "tailoring" the major source applicability thresholds under the PSD and Title V air operating permit programs. On March 21, 2011, USEPA issued a proposed *Deferral for CO_2emissions from bioenergy and other biogenic sources under the Prevention of Significant Deterioration (PSD) and Title V Programs* ("Proposed Deferral Rule", 76 Fed. Reg. 15,249, 15,252-54), and Deferral Rule 76 Fed. Reg. at 43,492. The Deferral Rule provided a 3-year exemption for biogenic sources from a compliance obligation with respect to the Tailoring Rule. For purposes of this PSD permit application, the proposed biomass-fired cogeneration unit is a biogenic source, and its respective GHG compliance obligation falls within the scope of the deferral rule.

On February 19, 2013, USEPA made a final decision in issuance of PSD permit SAC 12-01 for this project. The PSD permit was subsequently administratively appealed within 30-days of the service of notice and heard by the Environmental Appeals Board (EAB). On July 13, 2013, the EAB remanded in part and denied in part the submitted appeals.

On July 12, 2013 (the day prior to the EAB decision), the US Court of Appeals made a decision to vacate the Deferral Rule. However, this decision is not, and will not become effective until the court issues a 'mandate'. At the date of this report, a mandate has not been issued and the vacatur is not in effect.

At SPI's sole discretion, this GHG BACT analysis has been prepared and is being submitted to USEPA as part of the PSD supporting documents for the Anderson cogeneration project. For purposes of this report, it is anticipated that the court mandate will be effective in the near future, and this report is intended to satisfy the compliance obligation under the existing Tailoring Rule, regardless of the Deferral Rule.

The first step of the Tailoring Rule, which began on January 2, 2011, and lasted until June 30, 2011, required sources already subject to the PSD permitting programs to meet that program's permitting requirements for greenhouse gases. New sources or modifications of existing sources expected to increase total greenhouse gas emission rates by 75,000 tpy or more, on a carbon dioxide equivalent (CO_2e) basis, and whose emissions exceed the PSD threshold for one or more criteria pollutants, are subject to PSD review for GHGs.

The second step of the rule, which started on July 1, 2011, and lasts until June 30, 2014, casts a wider net than the first. New construction projects expected to emit at least 100,000 tpy of total greenhouse gases on a CO_2e basis, or modifications at existing facilities that are expected to increase total greenhouse gas emissions by at least 75,000 tpy CO_2e will be subject to PSD permitting requirements, even if they do not significantly increase emissions of any other pollutant. Because the proposed biomass-fired cogeneration unit is expected to emit GHGs at a rate greater than 75,000 tpy CO_2e, the project is subject to PSD review for GHGs. Because there are no ambient standards or increments for GHGs, the only PSD requirement that applies to GHGs is that Best Available Control Technology (BACT) must be employed to reduce GHG emissions from the proposed unit.

1.1 Project Information

SPI is a family-owned wood-products company based in Redding, California. SPI currently operates an existing lumber manufacturing facility in Anderson, California. SPI intends to construct a new cogeneration unit to replace the existing biomass-fired unit at the Anderson facility; the new unit would also burn biomass fuel to produce steam that would be used to generate electricity and to heat existing lumber dry kilns at the facility.

The cogeneration unit will consist of a biomass-fired water tube boiler with a step grate and dual-chamber pyrolysis and combustion system, a cooling tower, a steam turbine, and an electrical generator. The boiler will burn biomass fuels to produce high-pressure steam for the steam turbine. The steam turbine will drive the electrical generator, which will be capable of generating up to 31 megawatts (MW) of electricity, approximately 7 MW of which will be used to power on-site equipment; the remainder will be sold to a public utility. Low-pressure steam will be taken from the steam turbine through a controlled extraction and used to heat the dry kilns.

1.2 BACT Analysis Process

BACT is defined at 40 CFR 52.21(b)(12) as:

> *an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology.*

> *Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

The process for conducting BACT analyses for criteria pollutants is relatively well established because it has been implemented for decades. Although there is a wide range of controls and associated costs that could be considered for criteria air pollutants, permit-issuing agencies have an understanding of which emission control options are appropriate and cost effective. In contrast, BACT analyses, BACT determinations, and cost-effectiveness criteria for GHGs are virtually non-existent.

In March 2011, USEPA issued updated guidance for conducting BACT analyses for GHGs (hereafter referred to as "the March 2011 Guidance"). USEPA recommended (but did not require) that permitting agencies apply to GHGs the same "top down" process applied to determine criteria pollutant BACT. In this process, potentially available control technologies are identified and evaluated for application to the proposed project. Feasible options are ranked in descending order of control effectiveness. The most stringent alternative is examined and is established as BACT unless the applicant demonstrates and the permitting authority agrees that energy, environmental or economic impacts justify a conclusion that the most stringent technology is not achievable. In that case the next stringent alternative is considered. The top-down analysis process is comprised of the following steps:

- Step 1 – Identify Available Control Technologies. Identify all available control techniques that could potentially be applied to control emissions of the regulated pollutants from the emission units.

- Step 2 – Eliminate Technically Infeasible Alternatives. If any of the control techniques cannot be successfully used on the emission units due to technical difficulties, document this finding. Such control techniques would not be considered further in the BACT analysis.

- Step 3 – Rank Technically Feasible Alternatives. Assess the performance of each control technique and rank them beginning with the most effective control technique.

- Step 4 – Evaluate Economic, Energy, and Environmental Impacts. Estimate emission reductions, annual costs, cost effectiveness, energy impacts, and other environmental impacts of the controls techniques. Detailed cost effectiveness information is presented for the most effective control and for other control techniques that are in the least cost envelope.

- Step 5 – Select BACT. Identify the most effective option not rejected based on energy, environmental, and economic impacts.

Each step is discussed further in the sections that follow.

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1.2.1 Step 1 – Identify Available Control Technologies

The first step in the top-down procedure is to identify all available control technologies and emission reduction options for each subject pollutant. Available control technologies are those with a practical potential for application to the emission unit. For criteria pollutants, applicants typically identify appropriate control technologies by reviewing the following sources of information:

- USEPA RACT/BACT/LAER Clearinghouse (RBLC)
- USEPA Control Technology Center (CTC)
- Recent Permit Actions by other State and Local Agencies, and
- Vendor Information

Because BACT for GHGs is a relatively new requirement, there are few BACT precedents, let alone precedents for biomass-fired cogeneration units, and none that include associated lumber drying steam requirements. In preparing this BACT analysis, ENVIRON reviewed BACT analyses for combined cycle power plants (e.g., Russell Energy Center, Avenal Energy Power Plant, and CPV Vaca Station Power Plant), a proposed combination refinery and integrated gasification combined cycle (IGCC) facility in South Dakota (Hyperion Energy Center), and several recent biomass-fired electric generation and cogeneration facilities (e.g., Montville Power, We Energies/Domtar Biomass Energy Project, Abengoa Bioenergy Biomass, Beaver Wood Energy, and North Springfield Sustainable Energy). The biomass-fired projects all indicated that BACT for GHGs is good boiler design, good combustion practices, and efficient operation.

Consistent with these precedents and EPA's March 2011 Guidance, this analysis demonstrates that the design of the proposed biomass-fired cogeneration unit will achieve a very high degree of energy efficiency. In BACT parlance, this is considered "lower-polluting processes/practices" as opposed to post-combustion or "end-of-stack" controls. Given the limited technological options available for end-of-stack GHG emission controls, EPA's initial BACT guidance emphasizes energy efficiency. In addition to reducing GHG emissions, energy efficiency also minimizes criteria and toxic air pollutant emissions.

A control technology must be "available" to be considered BACT. According to EPA's draft 1990 NSR manual "'[a]vailable' means that the method's systems and techniques are commercially available." BACT also does not require the applicant to participate in a research and development project to determine if a technology is "available" for a particular use.

Theoretical, experimental or developing technologies are not "available" under BACT. Technologies with questionable or dubious reliability are likewise not considered "available" under BACT, and the applicant is not required to use them. BACT does not require an applicant to speculate as to whether an undemonstrated technology will effectively control the pollutant in question from the proposed source. Applicants are not required to accept the risk that a theoretically feasible, but unproven, technology will effectively and economically reduce emissions from the proposed source.1

1.2.2 Step 2 – Eliminate Technically Infeasible Control Technologies

The second step in performing the top-down BACT analysis is to eliminate all technically infeasible options. The determination that a control technology is technically infeasible is source-specific and based upon physical, chemical, and engineering principles. Technical feasibility is addressed in EPA's March 2011 Guidance:

> EPA considers a technology to be technically feasible if it has been demonstrated in practice or is available and applicable to the source type under review. The term "demonstrated" is focused on the technology being used in the same type of source, such as a similar plant producing the same product. Therefore, EPA considers a technology to be "demonstrated," if it has been installed and operated successfully on the type of source at issue.

Prior guidance and judicial decisions confirm that "feasible technology" means design or equipment that has progressed beyond the conceptual and pilot testing phases, is commercially available, and has been demonstrated on a full-scale emission unit of the type of that is the subject of the BACT analysis, for a period of time sufficient to indicate reliable operation. These criteria are especially important for GHG BACT analyses due to the unproven nature of many GHG control schemes.

"Demonstrated in practice" is another important concept that addresses the question of whether a technology should be considered available. In its New Source Review Improvement Rule (issued November 22, 2002), EPA included a definition of "demonstrated in practice." This definition prescribes which technologies must be considered in BACT and LAER determinations by defining the information that must be reviewed to identify candidate technologies, the amount of time the technology must be in use, and its performance during that time. A technology installed and operating on an emissions unit (or units) must meet the following criteria to be considered "demonstrated in practice:"

- Has operated at a minimum of 50 percent of design capacity for at least 6 months; and
- The pollution control efficiency performance has been verified by either:

  1) a performance test, or

  2) performance data collected at the maximum design capacity of the emissions unit (or units) being controlled, or 90 percent or more of the control technology's designed specifications.

1 USEPA, "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Are Permitting, Draft," October 1990. Pages B.17 – B.21.

Although this definition of "demonstrated in practice" does not specifically apply to the analysis presented in this report, it does provide some useful guidance for evaluating whether certain technologies are "available," and therefore worthy of consideration as BACT.

1.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step in the top-down BACT analysis is to rank all remaining control technologies with respect to control effectiveness (i.e., by emission limit or removal efficiency, as applicable). The emission limit or removal efficiency used in the ranking process is that which the technology has demonstrated can be achieved consistently under reasonably foreseeable worst-case conditions with an adequate margin of safety. A limit or removal efficiency that can be achieved only occasionally under best-case circumstances is not to be considered.

For GHGs, control options are ranked based on total CO_2e rather than the total mass or mass of individual GHGs.

1.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

In this step, an analysis is performed on each remaining control technology to determine whether the energy, economic, or environmental impacts from a given technology outweigh their benefits. Factors such as control efficiency, anticipated emission rate, expected emissions reduction, and economic, environmental, and energy impacts, are to be considered.

If the top-ranked technology is chosen, and there are no significant or unusual environmental impacts associated with that technology that have the potential to affect its selection, the BACT analysis is complete, and no further analysis is required. However, if the chosen technology is not the top-ranked option, the economic, environmental, and energy impacts of the chosen technology, and each more-effective technology, must be evaluated and compared to justify application of the selected technology.

In performing economic analyses, USEPA's Air Pollution Control Cost Manual, published in January 2002 (EPA/452/B-02-001) provides capital and annual operating cost factors that can be used in determining the installation and operating costs of each control technology. Actual vendor installation and operation costs were used where applicable.

Cost-effectiveness evaluations for greenhouse gases are to be conducted based on reductions in CO_2e. However, as acknowledged by EPA in its March 2011 Guidance, no cost effectiveness criteria have been established for GHGs. Furthermore, there are no means by which to evaluate the environmental impacts of GHG emissions at the stationary source level. Consequently, comparisons of environmental impacts associated with GHG emissions with those of collateral criteria pollutant emissions are not possible.

1.2.5 Step 5 – Select BACT

The final step is selection of the most stringent and technically feasible emission limit and corresponding technology that was not eliminated based upon adverse economic, environmental, and energy impacts. EPA's March 2011 Guidance notes that a GHG permit may limit CO_2e based on a mass emission rate (lb/hr) or other metrics. EPA also notes that "since the environmental concern with greenhouse gases is with their cumulative impact in the environment, metrics should focus on longer-term averages (e.g., 30- or 365-day rolling average) rather than short-term averages (e.g., 3- or 24-hr rolling average)."

Given decades of experience with the top-down BACT analysis, the process has resulted in a number of agency and judicial decisions that have served to guide subsequent BACT determinations:

- BACT determinations are made "on a case-by-case basis," taking into account site-specific and source-specific characteristics. These characteristics may include, among other things, the type of fuel or raw materials that will be used, and the type and size of the emissions unit. A high degree of technical judgment must be exercised in any BACT analysis as there are various sizes and ages of the emissions units covered by an analysis.
- BACT must be achievable. The Environmental Appeals Board (EAB) has recently stated that, while BACT is forward-looking, "the word 'achievable'…constrains the permit issuer's discretion by prohibiting BACT limits that would require pollution reductions greater than what can be achieved with available methods." The EAB concluded that "the permit issuer may take into account the absence of long-term data, or the unproven long-term effectiveness of the technology, in setting the emissions limitation that is BACT for the facility." The EAB further stated that the BACT analysis "must be solidly grounded on what is presently known about the selected technology's effectiveness," and that "emissions limitations achieved by other facilities, and corresponding control technologies used at other facilities are an important source of information in determining" BACT.

EPA's March 2011 Guidance affirms that vendor confidence in emission control efficiency should be considered: "[t]he willingness of vendors to guarantee a certain level of performance should be considered by the permitting authority later in the BACT process when proposing a specific emissions limit or level of performance in the PSD permit."

Finally, the chosen BACT emission limit must not be less stringent than any applicable federal NSPS, NESHAP, or state-specific emission standard. It should be noted, however, that currently there are no federal NSPS, NESHAP, or California State GHG emission standards that apply to biomass-fired cogeneration units.

1.3 Cost-Effectiveness Analysis

In Step 4 of the top-down BACT analysis process, cost effectiveness is used to assess the economic impact of emission reduction alternatives. The cost effectiveness of a control option is defined as dollars per ton ($/ton) of pollutant removed or avoided when compared with some baseline (usually the uncontrolled emission rate), and is calculated as follows:

$$\frac{\text{Total Annualized Costs of Control Option}}{(\text{Baseline Annual Emissions - Control Option Annual Emissions})}$$

In cases where more than one control option is being considered, an incremental cost effectiveness is often calculated, as follows, to determine the cost per ton of the additional quantity of pollutant reduced at some additional expense:

$$\frac{(\text{Total Annualized Costs of Control Option} - \text{Total Annualized Costs of Next Control Option})}{(\text{Control Option Annual Emissions} - \text{Next Control Option Annual Emissions})}$$

1.3.1 Cost Methodology

The total annualized cost of each control is calculated as follows:

i) Total Annual Costs = Annualized Capital Costs + Annual Operations & Maintenance Costs

ii) Annualized Capital Costs = Capital Recovery Factor x Total Direct and Indirect Capital Costs

Where:

Capital Recovery Factor (CRF) = $((1+i)^{n} - 1)$

and, assuming:

Life of Equipment, n = 20 years

Annual Interest Rate, i = 7%

CRF = 0.094393

1.3.2 Cost Criteria

Step 4 of the BACT process addresses economic, energy, and environmental impacts associated with feasible control options. The economic evaluation enables an applicant an opportunity to demonstrate that the costs of pollutant removal for a particular control option are disproportionately high. However, EPA's March 2011 Guidance acknowledges "there is not a wealth of GHG cost effectiveness data from prior permitting actions for a permitting authority to review and rely upon when determining what cost level is considered acceptable for GHG BACT." EPA also acknowledges that cost effectiveness criteria historically applied to criteria pollutant emissions are not appropriate for greenhouse gases because greenhouse gas emissions tend to be orders of magnitude greater than criteria pollutant emissions. Given this early stage of greenhouse gas BACT review, there is very little information that enables applicants or reviewing agencies to determine whether a control option is cost effective.

An Interim Report issued in February 2010 by the Climate Change Work Group of the Permits, New Source Review and Toxics Subcommittee to the EPA's Clean Air Act Advisory Committee, which includes industry, environmental, and regulatory groups, provided no consensus on greenhouse gas cost effectiveness, with values ranging from $3 per ton to $150 per ton. Some members supported not setting fixed cost effectiveness thresholds, and recommended that EPA provide guidance to permitting authorities on the range of cost effectiveness values based on the status of various control technologies.

An obvious source of carbon cost information is the value of carbon allowances or offsets. Analogous to EPA's acid rain program, an allowance is an authorization under a regulatory program to emit a certain quantity of carbon. However, a carbon offset is typically an emission reduction established outside of a regulatory program, and may or may not be recognized by a regulatory program.

The Regional Greenhouse Gas Initiative (RGGI, http://www.rggi.org) is the first mandatory, market-based effort in the United States to reduce greenhouse gas emissions. Ten Northeastern and Mid-Atlantic states have implemented a CO_2 cap, effective until 2014, after which the cap will be reduced by 2.5 percent each year until a total reduction of 10 percent is achieved by 2018. States sell nearly all emission allowances through auctions and invest the proceeds in consumer benefits such as energy efficiency, renewable energy, and other clean energy technologies.

At a RGGI auction held March 9, 2011, allowances averaged \$1.89 per ton of CO_2. "Future" allowances also averaged \$1.89 per ton, implying that the value of CO_2 allowances is not expected to change significantly in the near future. Eighty-five percent of the allowances available at the auction were purchased by electric utilities and affiliates.

RGGI-participating states currently allow regulated power plants to use a carefully-chosen group of qualifying offsets to meet up to 3.3 percent of their CO_2 compliance obligation. Examples of offset-eligible project categories include those that capture or destroy methane from landfills or through agricultural manure management operations.

Similar in nature to RGGI allowances, European Union Allowance units (EUAs) are sold in Europe as a mechanism for achieving an EU objective of a 20 percent reduction in carbon emissions by 2020 (compared to 1990 levels). The price of an EUA in April 2011 was approximately 16 euros (equivalent to about \$23) per metric tonne.

The Chicago Climate Exchange (CCX) was a voluntary, legally binding, GHG reduction and trading system until it closed in November 2010. At that time, the price of carbon credits (which had not traded on the CCX since February 2010) ranged between \$0.05 and \$0.10 per metric tonne of CO_2e.

The third, and most recent, auction of greenhouse gas allowances by the California Air Resources Board (CARB) for the California Cap-and-Trade program, held on May 3, 2013, resulted in a per-allowance price of \$14.00 for 2013 vintage allowances. An allowance gives the holder the right to emit 1 ton of GHG on a CO_2e basis. On the same date, the advance auction of 2016 vintage allowances resulted in a per-allowance price of \$10.71.

When developing the GHG Tailoring Rule, EPA used scaling to derive a Significant Emission Rate for greenhouse gases from the Significant Emission Rates for criteria pollutants. Applying a similar rationale, one could derive a greenhouse gas cost effectiveness criterion by scaling CO_2 emissions from CO emissions. Using a relatively conservative cost effectiveness criterion of \$10,000/ton, and emission factors for external natural gas combustion from EPA's AP-42 emission factor database (84 and 120,000 lb/scf for CO and CO_2, respectively), a comparable cost-effectiveness criterion for CO_2 would be \$7/ton (i.e., \$10,000 x 84 / 120,000).

In October 2010, Hyperion Energy Center (a proposed combination oil refinery and integrated gasification combined-cycle power plant) submitted a greenhouse gas BACT analysis to South Dakota Department of Environment and Natural Resources in support of a renewal of a previously issued PSD permit that calculated the cost effectiveness of implementing Carbon Capture and Storage (CCS) on a CO_2 vent, refinery process heaters, and combined cycle gas turbines. The calculated cost effectiveness of the various control options ranged from $43 to $124 per ton of CO_2e. Absent any established cost effectiveness criteria, the Hyperion BACT analysis cited the Chicago Climate Exchange offset prices (less than $1 per ton at the time) and the EU allowance prices ($12 per tonne at the time) and concluded that CCS was not cost effective.

We Energies provided a GHG BACT analysis in support of a permit application submitted to Wisconsin Department of Natural Resources proposing to install and operate a biomass-fired boiler. The GHG BACT analysis included cost-effectiveness calculations for systems to control methane (CH_4) and nitrous oxide (N_2O), but did not provide any cost-effectiveness criteria for comparison.

Lacking specific guidance from EPA or local agencies, and weighting several sources that imply values less than $2/ton against an EU Allowance of $23/tonne, SPI proposes a GHG cost-effectiveness threshold of $7/ton, derived by scaling the commonly-accepted cost-effectiveness threshold for criteria pollutants ($10,000/ton) using natural gas combustion emission factors.

2 Project Greenhouse Gas Emissions

The Tailoring Rule defined GHGs as an aggregate of: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). The proposed project has the potential to emit only three of these: CO_2, CH_4, and N_2O. All GHG emissions associated with the project will be generated by the cogeneration unit; the cooling tower will not emit any GHGs. The Tailoring Rule further defined CO2e as the sum of the mass emissions of the constituent GHG, each multiplied by the appropriate global warming potential (GWP) factor provided in Table A-1 of the Federal Mandatory GHG Reporting Rule (MRR, codified in 40 CFR Part 98).

The proposed cogeneration unit is assumed to have a maximum annual average heat input of 468 million British thermal units per hour (MMBtu/hr). A natural-gas-fired emergency feedwater pump used to circulate water through the cogeneration unit boiler in case of an emergency shutdown while disconnected from the grid, will have a maximum heat input of 2.16 MMBtu/hr, and will be operated a maximum of 100 hours per year for maintenance and testing purposes, in addition to any emergency use. Table 2-1 summarizes the calculations and shows that the proposed project has the potential to generate a maximum of approximately 433,000 tons of CO_2e per year.

Table 2-1. Greenhouse Gas Emission Rate Calculations – Proposed Equipment

Emission Unit	GHG	Emission Factor[1]		Global Warming Potential[2]	Emission Rate[3]	
		(kg/MMBtu)	(lb/MMBtu)		(lb/hr)	(tpy)
Cogeneration Unit	CO_2	93.8	207	1	96,800	424,000
	CH_4	3.20E-02	0.0705	21	33.0	145
	N_2O	4.20E-03	0.00926	310	4.33	19.0
	CO_2e	--	--	--	98,800	433,000
Gas-Fired Emergency Feedwater Pump	CO_2	53.02	116.9	1	253	12.6
	CH_4	0.001	0.0022	21	0.00476	0.000238
	N_2O	0.0001	0.00022	310	0.000476	0.0000238
	CO_2e	--	--	--	253	12.6
Total	CO_2	--	--	1	97,000	424,000
	CH_4	--	--	21	33.0	145
	N_2O	--	--	310	4.33	19.0
	CO_2e	--	--	--	99,100	433,000

1 The kg/MMBtu emission factors for combustion of wood and wood residual solid biomass fuel, and natural gas, are from 40 CFR Part 98, Tables C-1 and C-2; these were converted to lb/MMBtu using 2.2046 lb/kg.

2 100-year time horizon global warming potential (GWP) – from 40 CFR Part 98, Table A-1.

3 Calculated by multiplying the emission factor by the maximum annual average heat input (468 MMBtu/hr for the cogeneration unit and 2.16 MMBtu/hr for the emergency pump engine). Annual emission rates are based on 8,760 hr/yr operation for the cogeneration unit, and 100 hr/yr for the emergency pump engine. CO_2e was calculated by multiplying each individual emission rate by the applicable GWP factor, and summing.

While the vast majority of emissions will be from combustion of wood and wood-residual solid biomass fuel, the proposed unit will be equipped with two 62.5 MMBtu/hr natural gas burners that will be used during startup, and, potentially, during shutdown and for flame stabilization.

Operation of the natural gas burners will not exceed 10 percent of the annual heat input capacity of the boiler, or 409,934 MMBtu/yr (468 MMBtu/hr * 8.760 hr/yr * 10%). Based on that maximum annual heat input and the CO_2e emission factor for natural gas combustion from 40 CFR Part 98 (117 lb/MMBtu), the maximum GHG emissions from the natural gas burners will be 23,981 tpy. It should be noted that the CO_2e emission factor for natural gas combustion is less than the CO_2e emission factor for biomass fuel, so any displacement of biomass fuel by natural gas combustion would reduce the maximum annual GHG emission potential of the unit.

The proposed cogeneration unit will be started and shutdown as infrequently as possible. There is typically at least one outage period each year for maintenance; any additional shutdown-and-startup cycles will be the result of an unscheduled event. It takes approximately 12 hours to start the cogeneration unit; natural gas burners are used to heat the refractory for the first 6 hours, and then biomass fuel is phased in, which the gas firing is phased out over the final 6 hours. Shutdown takes approximately 1 hour to accomplish, and the natural gas burners are used only if elevated carbon monoxide (CO) levels are indicated by the continuous emissions monitoring system (CEMS). Based on the startup protocol outlined above, a calculated estimate of GHG emissions is provided in Table 2-2.

Table 2-2. Greenhouse Gas Emission Rate Calculations – Cogeneration Unit Startup

Firing Biomass Fuel				
GHG	Emission Factor (lb/MMBtu)	Hourly Emission Rate[1] (lb/hr)	Event Emission Rate[2] (lb/event)	
CO_2	207	96,770	580,622	
CH_4	0.282[3]	132	792	
N_2O	0.0370[3]	17	104	
CO_2e[4]		104,916	629,498	
Firing Natural Gas				
GHG	Emission Factor (lb/MMBtu)	Hourly Emission Rate[1] (lb/hr)	Event Emission Rate[2] (lb/event)	
CO_2	117	14,611	87,666	
CH_4	0.0022	0.276	1.65	
N_2O	0.00022	0.0276	0.165	
CO_2e[4]		14,625	87,752	
Total				
GHG		Average Hourly Emission Rate[1] (lb/hr)	Event Emission Rate[2] (lb/event)	Event Emission Rate (ton/event)
CO_2		55,691	668,288	334
CH_4		66	794	0.397
N_2O		9	104	0.0521
CO_2e[4]		59,771	717,250	359

1 Hourly emission rates are based on 468 MMBtu/hr when firing biomass, and 125 MMBtu/hr when firing natural gas.

2 Event emission rate is the hourly emission rate multiplied by 6 hours.

3 The CH_4 and N_2O emission rates were increased by a factor of 4 to reflect incomplete combustion during startup; a similar approach was taken when calculating CO and VOC emission rates during startup.

4 Calculated using 100-year time horizon global warming potentials (GWPs) from 40 CFR Part 98, Table A-1.

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The facility currently includes a biomass-fired boiler with a maximum annual average heat input capacity of 116.5 MMBtu/hr, and a circuit breaker and two switches that utilize sulfur hexafluoride (SF_6) as a dielectric medium. The existing boiler will not be used concurrent with the proposed cogeneration unit, but the existing switchgear will continue to be used by the new unit, unchanged from its current configuration. During the period that the new unit is commissioned it will operate concurrent with the existing unit, but none of the steam will be used for commercial purposes, and the new generator will not be connected to the existing switchgear. Table 2-3 summarizes the GHG emission rate calculations for the existing equipment at the facility.

Table 2-3. Greenhouse Gas Emission Rate Calculations – Existing Equipment

Emission Unit	GHG	Emission Factor (Heat Input)[1]		Global Warming Potential[2]	Emission Rate[3]	
		(kg/MMBtu)	(lb/MMBtu)		(lb/hr)	(tpy)
Biomass-Fired Boiler	CO_2	93.8	207	1	24,100	105,000
	CH_4	3.20E-02	0.0705	21	8.21	36.0
	N_2O	4.20E-03	0.00926	310	1.08	4.72
	CO_2e	--	--	--	24,600	108,000
Switchgear	SF_6	1% leakage/year		23,900	0.000217	0.000950
	CO_2e	--	--	--	5.18	22.7
Total	CO_2	--	--	1	24,100	105,000
	CH_4	--	--	21	8.21	36.0
	N_2O	--	--	310	1.08	4.72
	SF_6	--	--	23,900	0.000217	0.000950
	CO_2e	--	--	--	24,600	108,000

1 The kg/MMBtu emission factors for combustion of wood and wood residual solid biomass fuel are from 40 CFR Part 98, Tables C-1 and C-2; the lb/MMBtu emission factors are calculated by converting the kg/MMBtu emission factors using 2.2046 lb/kg.

2 100-year time horizon global warming potential (GWP – from 40 CFR Part 98, Table A-1.

3 The hourly emission rate for the existing biomass-fired boiler was calculated by multiplying the emission factor by the maximum heat input (116.4 MMBtu/hr); annual emission rates are based on 8,760 hr/yr operation. The annual SF_6 emission rate for the switchgear was calculated by multiplying the SF_6 capacity of the existing breaker and two switches (190 lb) by the annual leak rate of (1%, which was the industry standard at the time the equipment was installed); the hourly emission rate was based on the assumption that the leak rate is uniform throughput the year. CO_2e was calculated by multiplying each individual emission rate by the applicable GWP factor, and summing.

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3 Step 1 – Identify Available Control Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies. While step 1 is intended to include all possibilities, there are limits to the scope of the first two option categories (i.e., inherently low-emitting processes and clean fuels). The list of options in step 1 need not include those that fundamentally redefine the nature of the proposed source or modification. The EPA's RBLC (RACT/BACT/LAER Clearinghouse database) was queried to identify GHG BACT determinations associated with recently permitted biomass-fired boilers. The five most recent facilities are summarized in Table 3-1. In each case, BACT for GHGs was determined to be efficient operation and good operating practices (also referred to as good combustion practices). In all cases where the BACT process was available for review, carbon capture and sequestration/storage (CCS) was rejected as a viable option. In one of the recent BACT analyses, other add-on control alternatives (oxidation catalysts, thermal oxidation, non-selective catalytic reduction (NSCR), selective catalytic reduction (SCR) with N_2O catalyst, elimination of selective non-catalytic reduction (SNCR)) were evaluated to reduce one or more GHG, but all were rejected.

Table 2-3. Summary of GHG BACT Determinations for Biomass-Fired Boilers in RBLC

Facility	State	Permit Issuance Date	Heat Input (MMBtu/hr)	GHG BACT Determination	Rejected GHG Control Alternatives
North Springfield Sustainable Energy Project	VT	4/19/2013	464	Efficient Operation, Combined Heat & Power (CHP), Good Operating Practices (GOP)	Carbon Capture & Storage (CCS), Fuel Switching
Beaver Wood Energy Fair Haven LLC	VT	2/10/2012	482	Efficient Operation, CHP, GOP	CCS, Fuel Switching
WE Energies – Rothschild	WI	3/28/2011	781	Efficient Operation, CHP, GOP	CCS, Oxidation Catalysts, Thermal Oxidation, Non-Selective Catalytic Reduction (NSCR), Selective Catalytic Reduction (SCR) with N_2O Catalyst, Elimination of Selective Non-Catalytic Reduction (SNCR)
Abengoa Bioenergy Biomass of Kansas LLC	KS	9/16/2011	500	Use of Low-Carbon or Carbon-Neutral Fuel, Efficient Operation, CHP, GOP	CCS
Montville Power LLC	CT	4/6/2010	600	Efficient operation, GOP	N/A[1]

1 Issued permit does not outline the BACT determination process for GHGs; unable to obtain an associated technical support document

Considerable argument and litigation has been generated previously over what constitutes "redefinition of the source." One of the most recent approaches, outlined by the Environmental

Appeals Board (EAB), is contained in a 2009 ruling to remand a permit issued to Desert Rock Energy Co., LLC. In that ruling, which referred extensively to a previous ruling (Prairie State Generation Co., LLC), the EAB says that the reviewing agency should seek to answer the question: "when does the imposition of control technology require enough of a redesign of the proposed facility that it strays over the dividing line to become an impermissible redefinition of the source?"

In response to its own question, the EAB stated that "the permit applicant initially defines the proposed facility's end, object, aim, or purpose – that is the facility's basic design, although the applicant's definition must be for reasons independent of air permitting." Furthermore, the permit issuer should "take a 'hard look' at the application determination in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility, while keeping in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility."

The discussion in the prior paragraphs notwithstanding, EPA has requested that SPI consider fluidized bed boiler (FBB) designs in step 1 of the BACT process. SPI contacted FBB manufacturers and sought out facilities with operations similar to that of the Anderson facility that employed FBBs. Manufacturers of FBBs indicated that their designs were not appropriate for use when the boiler would be operated at loads less than 50 percent of the rated capacity (i.e., in "turndown" mode). First, the extent of turndown that will be required of the installed unit makes FBBs impractical. Second, the unit will be expected to achieve significant load changes (e.g., 100 percent load to 50 percent load) within a short period of time (e.g., 1 hour). The thermal inertia of the fluidized bed material, which allows introduced fuel to be heated to ignition temperature without significantly affecting the bed temperature, prevents FBB units from accommodating abrupt load changes.

Furthermore, SPI was unable to identify any lumber manufacturing facilities using biomass fuel to generate steam to heat lumber dry kilns that utilized an FBB. An additional practical concern is that the proposed cogeneration unit will supply steam to generate electricity in addition to heating lumber dry kilns. The power purchase agreement associated with supplying generated electricity to the grid requires a high level of availability; the electrical generation commitments for this unit are not compatible with accommodating an exploratory or innovative application of existing technology.

As discussed in a letter sent to USEPA Region 9 on January 23, 2012 by ENVIRON on behalf of SPI, a stoker boiler design was chosen for the project because operation in turndown modes less than 50 percent would be possible. A USEPA information document estimates that FBB designs are capable of unburned fuel rates as low as 0.25 percent, which suggests more efficient operation.[2] Teaford (now Dieffenbacher), the designer and manufacturer of the boiler selected by SPI for the proposed cogeneration unit, estimates that their stoker design can

2 USEPA, Combined Heat and Power Partnership. "Biomass Combined Heat and Power Catalog of Technologies." September 2007.

achieve an unburned fuel rate of approximately 1 percent. Nevertheless, more efficient operation does not mitigate the fact that FBB designs are incapable of accommodating the project's intended objectives (i.e., ability to achieve turndown modes less than 50 percent and abrupt load changes), and are therefore rejected as viable alternatives.

In the March 2011 Guidance document, USEPA acknowledges that, although "clean fuels" are to be considered in step 1 of the BACT analysis, the initial list of control options does not need to include "clean fuel" options that would fundamentally redefine the source. In this case, use of the biomass fuel generated by the existing facility is a central purpose for the project. Substitution of any other fuel, lower-carbon-containing or otherwise, would drastically alter the overall goals of the proposed project.

3.1 Carbon Dioxide

Carbon dioxide (CO_2) is a by-product of complete combustion. Altering the combustion process to reduce CO_2 emissions would increase emissions of "traditional" air pollutants such as carbon monoxide (CO) and volatile organic compounds (VOCs). Maximizing the heat transfer efficiency of the boiler and the mechanical efficiency of the steam turbine and generator minimizes the quantity of fuel combusted, and therefore the quantity of CO_2 generated, per unit of steam or electricity generated. Approaches intended to reduce fuel consumption while increasing output are typically referred to as "good boiler design, good combustion practices, and efficient operation."

Add-on technologies that are able to remove, or "capture," CO_2 from the post-combustion exhaust stream have been developed, though none have been used to capture CO_2 from a biomass combustion unit. Following capture, the CO_2 would be transported and stored permanently, or "sequestered," in a geologic formation. Such systems, referred to as "carbon capture and sequestration/storage" (CCS), are not yet commercially available, and the U.S. Department of Energy does not expect them to be available until approximately 2025.

The March 2011 Guidance document states that, if the proposed emission unit "can demonstrate that utilizing a particular type of biogenic fuel is fundamental to the primary purpose of the project," then "the options listed as Step 1 of a top-down BACT analysis of GHGs may be limited to (1) utilization of biomass fuel alone, (2) energy efficiency improvements, and (3) carbon capture and sequestration."

3.2 Methane

Like carbon monoxide (CO) and volatile organic compounds (VOCs), methane (CH_4) emissions are generally the result of incomplete fuel combustion. In the case of biomass, volatile compounds (including CH_4) are released as the fuel is heated in the furnace, some portion of which escapes combustion by improper mixing with oxygen or being confined to zones of relatively low temperature.

Proper combustion practices and use of a properly designed boiler maximizes complete combustion, and minimizes emissions of volatiles, including CH_4. Add-on controls used to remove volatile compounds from gas streams include adsorption systems and thermal or catalytic oxidation systems. Adsorption systems pass the gas stream though canisters filled with activated carbon or zeolite, and the volatile compounds are trapped in pores located on the carbon or zeolite particles. When the carbon approaches saturation, the canister is replaced and processed to remove the volatile compounds, which are recovered or destroyed. Oxidation systems increase the temperature of the gas stream until the CH_4 oxidizes, forming CO_2 and water. Thermal oxidizers destroy volatile compounds using a flame, while catalytic oxidation uses a catalyst to promote oxidation reactions at temperatures lower than those at which combustion typically takes place.

3.3 Nitrous Oxide

Unlike nitric oxide (NO), which is the product of high combustion temperatures (greater than 730 °C or 1,350 °F), nitrous oxide (N_2O) is the result of lower combustion temperatures (less than 800 °C or 1,475 °F). Its formation can be limited to some extent by using proper combustion techniques and a properly designed boiler that promotes uniform furnace temperatures. Typically, furnace conditions that favor CH_4 formation, also favor N_2O formation.

Add-on controls to reduce N_2O emissions include: non-selective catalytic reduction (NSCR), thermal destruction, and catalytic destruction. In the 1970s, NSCR systems were widely used to control N_2O and oxides of nitrogen (NO_X) emissions from adipic and nitric acid production operations, but high energy costs reduced the popularity of this approach. Currently, NSCR systems have been used to reduce emissions from reciprocating engines operated in a rich-burn or stoichiometric mode. In general, NSCR systems pass the exhaust gases over catalysts, which use metals (e.g., platinum, rhodium, palladium) to convert NO_X, CO, and VOCs to water, nitrogen, and carbon dioxide. Unburned hydrocarbons in the exhaust are used as a reducing agent to enable one catalyst to convert N_2O and NO_X, while CO and VOCs are oxidized by another catalyst. In cases where the option to consistently operate in a fuel-rich or stoichiometric mode to provide the reducing agent is not available, natural gas can be injected to act as the reducing agent.

Thermal destruction of N_2O is achieved using a reducing flame burner combusting premixed methane or natural gas. The flame temperature must be maintained high enough to destroy the N_2O, but below 1,500 °C to minimize NO_X formation. Catalytic destruction is accomplished at lower temperatures (400 to 700 °C) using metal- or zeolite-based N_2O-decomposing catalysts.

Conventional commercially-available selective catalytic reduction (SCR) systems (i.e., those using titanium, tungsten, and vanadium-based catalysts) used to reduce emissions of nitric oxide (NO) and nitrogen dioxide (NO_2), as well as selective non-catalytic reduction (SNCR) systems, generate N_2O, so removal of such control systems would reduce N_2O emissions. However, at least two companies (BASF and Heraeus) have developed catalysts designed to simultaneously remove both N_2O as well as NO and NO_2.

4 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

4.1 Carbon Dioxide

In Step 1, use of biomass fuel, energy efficiency, and CCS were identified as potential control technologies, consistent with the EPA's March 2011 guidance.

<u>Biomass Fuel</u>

Combustion of biomass fuels, alone or in combination with other fuels, in boilers to generate steam is a long-standing practice. Biomass is one of the original boiler fuels, and it remains a feasible and often-used fuel.

<u>Good Boiler Design, Good Combustion Practices, Efficient Operation</u>

Maximizing the quantity of steam or electricity generated per unit of fuel combusted is the goal of most boiler designers and operators. Striving for energy efficiency is technically feasible within the limitations of the second law of thermodynamics. At maximum operation, the efficiency of the proposed boiler (i.e., the fraction of the energy in the fuel that is transferred to the steam) is expected to be approximately 70 percent. The efficiency of the electrical generator is, at full load, approximately 96 percent. The overall efficiency of the cogeneration unit will vary depending upon the quantities of steam used to heat the kilns and generate electricity, but is expected to vary between 37 and 53 percent.

<u>Carbon Capture and Sequestration</u>

In its findings and recommendations report, issued on January 24, 2011, the California Carbon Capture and Storage Review Panel concluded, among other things, that the technology "for the safe and effective capture, transport, and geological storage of CO_2 from power plants and other large industrial facilities" currently exists. However, not all components that comprise an effective CCS program are currently commercially available. Nevertheless, for purposes of this BACT Analysis, CCS is considered to be a technically feasible control alternative for biomass-fired boilers.

There are three approaches to CO_2 capture that are generally applicable to power generation:

- Pre-combustion systems designed to separate CO_2 and hydrogen (H_2) from produced syngas,
- Post-combustion systems designed to separate CO_2 from flue gas, and
- Oxy-combustion that uses high-purity oxygen (O_2) instead of air, which produces flue gas composed largely of CO_2.

Of these, only post-combustion systems will be considered in this BACT analysis for application to a biomass-fired boiler, notwithstanding the fact that it has never been applied to exhaust from such a unit. Use of a pre-combustion system would require a gasification unit to produce syngas from the biomass fuel, which would amount to redefining the source. Oxy-combustion of biomass fuels is currently in the experimental phase, and is typically in the context of being co-fired with coal.

4.2 Methane

In Step 1, proper combustion, thermal oxidation, and catalytic oxidation were identified as possible alternatives for CH_4 reduction.

<u>Good Boiler Design, Good Combustion Practices, Efficient Operation</u>

For boilers combusting biomass, good boiler design, good combustion practices, and efficient operation are ubiquitous approaches used to reduce CO and hydrocarbon (including CH_4) emissions, therefore, they are considered technically feasible for control of CH_4 emissions.

<u>Adsorption</u>

Adsorption systems use porous material such as activated carbon or zeolite to capture gaseous pollutants. However, compounds are captured with varying efficiencies, and light hydrocarbons e.g., CH_4) have poor removal efficiencies, typically less than 50 percent. In addition, the CH_4 concentration in the cogeneration unit exhaust stream will be small (i.e., less than 1 percent by volume), further reducing the capture efficiency. For these reasons, adsorption systems have never been used to remove CH_4 from combustion unit exhaust streams. Using adsorption technology to reduce CH_4 emissions from a biomass-fired boiler in not considered technically feasible.

<u>Thermal Destruction</u>

To thermally oxidize a pollutant in an exhaust stream, a combustor is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support a flame are introduced. While the thermal oxidizer may destroy a portion of the small amount of CH_4 present in the exhaust (i.e., less than 1 percent by volume), the oxidizer itself is likely to generate additional air pollutants (e.g., NO_X, CO, VOCs, and CH_4) such that there is a net increase in emissions. In addition, a thermal oxidizer has never been used to reduce CH_4 emissions from a biomass-fired boiler. Control of CH_4 using thermal oxidation is considered speculative and not achieved in practice for a biomass-fired boiler, and, therefore, not technically feasible for reducing CH_4 emissions from a biomass-fired boiler.

<u>Catalytic Destruction</u>

When applied to boilers, the intent of a catalytic oxidation system is to reduce CO and, to a lesser extent, VOC and PM emissions. As discussed in the criteria pollutant BACT analysis submitted with the PSD permit application, while catalytic oxidation is not experimental, application to biomass-fired boilers is uncommon and difficult. Regardless of whether the catalyst is located upstream of downstream of a particulate control device (e.g., an electrostatic precipitator), alkali compounds in the exhaust gas deactivate the catalyst. To counteract the deactivation, large quantities of catalyst must be deployed and frequently replaced, resulting in unpredictable boiler availability and control system costs. Nevertheless, application of a catalytic oxidation system to reduce CH_4 emissions from a biomass-fired boiler is technically feasible.

4.3 Nitrous Oxide

In Step 1, proper combustion, thermal destruction, catalytic destruction, NSCR, removal of SCR systems, and addition of N_2O-abating SCR systems were identified as possible alternatives for N_2O reduction.

<u>Good Boiler Design, Good Combustion Practices, Efficient Operation</u>

For boilers combusting biomass, good boiler design, good combustion practices, and efficient operation are ubiquitous approaches used to reduce combustion byproducts other than CO_2 and water (including N_2O), therefore, they are considered technically feasible for control of N_2O emissions.

<u>Thermal Destruction</u>

Similar to the application of a thermal oxidizer to destroy CH_4, discussed above, the thermal oxidizer may destroy the relatively small amount of N_2O in the exhaust (i.e., less than 1 percent by volume), but the combustor itself is likely to generate air pollutants (e.g., NO_X, CO, SO_2, and N_2O) such that there is a net increase in emissions. As for CH_4, a thermal oxidizer has never been used to reduce N_2O emissions from a biomass-fired boiler. Use of this technology to reduce N_2O emissions from biomass-fired boilers is considered speculative and not achieved in practice, and therefore not technically feasible for reducing N_2O emissions from a biomass-fired boiler.

<u>Catalytic Destruction</u>

When applied to boilers, the intent of a catalytic oxidation system is to reduce CO and, to a lesser extent, VOC and PM emissions. As discussed in the criteria pollutant BACT analysis submitted with the PSD permit application, while catalytic oxidation is not experimental, application to biomass-fired boilers is uncommon and difficult. Regardless of whether the catalyst is located upstream of downstream of a particulate control device (e.g., an electrostatic precipitator), alkali compounds present in the exhaust gas deactivate the catalyst. To counteract the deactivation, large quantities of catalyst must be deployed and frequently replaced, resulting in unpredictable boiler availability and control system costs. Nevertheless, application of a catalytic oxidation system to reduce N_2O emissions from a biomass-fired boiler is technically feasible.

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Non-Selective Catalytic Reduction Systems

NSCR systems have primarily been developed to reduce N_2O emissions from adipic and nitric acid production operations; as acid production facility designs improve, NSCR is being phased out in favor of more economical alternatives. There are no instances of an NSCR system being applied to reduce N_2O emissions from a biomass-fired boiler, and because significant differences exist between the exhaust from adipic and nitric acid operations and that of a biomass-fired boiler (i.e., typical N_2O concentration in exhaust from a nitric acid plant is typically over 1,000 ppm, while the concentration in biomass-fired boiler exhaust is approximately 10 ppm), it is unlikely that the technology could be transferred effectively and economically. NSCR is therefore considered not technically feasible for control of N_2O from biomass-fired boilers.

Removal of Selective Non-Catalytic Reduction Systems

An SNCR system is proposed by SPI to reduce NO_X emissions from the biomass-fired boiler. It is technically feasible to not install such a system.

Removal of Conventional Selective Catalytic Reduction Systems

SPI does not propose to install a conventional SCR system to reduce NO_X emissions from the biomass-fired boiler. The criteria pollutant BACT analysis provided with the PSD permit application indicated that SCR was technically feasible, but had a still-unproven track record of reliable performance associated with biomass-fired boilers. Since no SCR system is proposed for installation on the biomass-fired boiler, it is technically infeasible to not install such a system.

Addition of N_2O-Abating Selective Catalytic Reduction Systems

The criteria pollutant BACT analysis provided with the PSD permit application concluded that conventional SCR systems were technically feasible for reducing NO_X emissions from biomass-fired boiler; therefore, N_2O-abating SCR systems are also considered technically feasible.

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5 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility, are ranked, starting with the most effective. The March 2011 Guidance says that "to best reflect the impact on the environment, the ranking of control options should be based on the total CO_2e rather than the total mass or mass for the individual GHGs. Before ranking all feasible control alternatives from the previous section are ranked together, the effectiveness of each on a CO_2e basis is discussed.

Good Boiler Design, Good Combustion Practices, Efficient Operation

The proposed project would operate in a manner that minimizes emissions of all pollutants, and maximizes the energy derived from the fuel consumed. Thus, these measures, in combination, are considered the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to these measures.

Biomass Fuel

The proposed boiler will be fired exclusively using biomass fuel, and SPI expects approximately 75 percent of that fuel to be comprised of sawmill residues from the Anderson sawmill and the nearby Shasta Lake sawmill. The remaining 25 percent is expected to be a combination of in-forest residues, agricultural residues from orchards in the Sacramento Valley, and urban wood residues diverted from landfills. Efficiently combusting mill residues, in-forest residues, and agricultural residues to generate steam and electricity results in less net GHG emissions (i.e., less CH_4 and N_2O are generated) than if those same residues were allowed to decompose or be subject to open burning. In the March 2011 Guidance, EPA acknowledges that the combustion of lumber manufacturing residues to generate energy does not increase net atmospheric GHG stock.

Furthermore, SPI manages nearly 1.7 million acres of forest land in California using sustainable forestry practices, and most of the carbon in the wood harvested from those forest lands remains sequestered in produced lumber. SPI replants harvested areas within a year, and plants an average of 6 million seedlings each year. The combined effect of: (1) younger trees taking up more carbon than harvested mature trees, (2) the sequestration of carbon in produced lumber, and (3) the most-effective conversion of residues to CO_2 by combustion in the proposed boiler is that SPI's operations serve to reduce atmospheric CO_2 stocks.

Carbon Capture and Sequestration

A CCS system is comprised of three parts: (1) capturing the CO_2, (2) transporting the CO_2, and (3) permanently storing (i.e., geological storage) the CO_2 or using it in some beneficial way (i.e., enhanced oil recovery, industrial use). The effectiveness of the system to reduce CO_2 emissions is determined by the removal rate of CO_2 from the flue gas, and degree to which the CO_2 is retained while being transported and stored. Currently available technology can capture approximately 90 percent of the post-combustion CO_2 in flue gas.[3] However, due to the considerable energy requirements for the capture and compression of the CO_2, the electrical generating capacity of the proposed cogeneration unit would have to be increased by 40 to 60 percent, which would increase the project's emission "footprint" by increasing both criteria pollutants and GHGs. Although 90 percent of the additional CO_2 generated would also be captured, the net CO_2 reduction would be reduced from 90 percent to 86 percent.[4]

Transport of CO_2 by pipeline is a mature technology, and expected losses of CO_2 in a pipeline would be minimal. While the fundamental physical processes and engineering aspects of geological storage of CO_2 are well understood, and there are active successful demonstration projects, it is not yet a commercially available alternative.[5] Enhanced oil recovery (EOR) uses CO_2 extract additional crude oil from producing wells. The majority of EOR activity is in the Permian Basin covering west Texas and southeastern New Mexico, and almost all of the CO_2 used there comes from large, high purity, geological CO_2 reservoirs in the same area. Projects that use anthropogenic CO_2 for EOR exist, or are under development, in Wyoming, Saskatchewan, and west Texas.[6] The best candidates for using captured CO_2 industrially include:

- Feedstock for urea yield boosting
- Working fluid for enhanced geothermal systems (EGS)
- Feedstock for polymer processing
- Algae cultivation
- Feedstock for carbonate mineralisation
- Concrete curing
- Bauxite residue carbonation
- Feedstock for liquid fuel production
- Enhanced coal bed methane recovery (ECBM)

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3 National Energy Technology Laboratory (NETL), "Cost and Performance Baseline for Fossil Energy Plants – Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2," November 2010. DOE/NETL-2010/1397. Page 18.
4 424,000 tpy CO_2 increased by 40 percent to account for the additional energy requirements of a CCS system is approximately 593,600 tpy CO_2; assuming 90 percent of the CO_2 is removed from the exhaust, results in an emission rate of approximately 59,360 tpy CO_2. The net reduction in CO_2 emissions is 1 – (59,360 / 424,000) = 0.86.
5 International Energy Agency (IEA, "Technology Roadmap: Carbon Capture and Storage," 2013. Pages 16-17.
6 NETL, "Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution," March 2010.

Of these, only urea yield-boosting is considered a mature technology that is already applied on a large scale, and has the potential for significant growth in the short term.[7]

In summary, CO_2 capture, transporting captured CO_2 by pipeline, and using captured CO_2 industrially for EOR or urea yield boosting are considered technically feasible. Geological storage of captured CO_2 is considered technically infeasible based on the lack of viable commercial availability.

A CCS system would not decrease the quantities of CH_4 and N_2O in the exhaust; in fact, the increase in emissions of those GHG compounds as a result of the additional capacity needed to power the CCS systems would degrade the net GHG reduction. On a CO_2e basis, CCS has the potential to reduce GHG emissions by approximately 83 percent.

Catalytic Destruction

Catalysts are a notoriously ineffective means of destroying CH_4 at typical exhaust temperatures (i.e., less than 450 °C), and the low availability of oxygen in combustion exhaust would further degrade the effectiveness. At best, a 40 percent reduction in CH_4 emissions has been documented when applied to internal combustion engines.[8]

When applied to exhaust from an adipic acid operation, catalytic destruction systems are effective, reducing N_2O emissions by up to 95 percent.[9] Although it is unclear that the same reductions would be realized when similar catalysts are applied to a biomass-fired boiler, the stated levels of control will be assumed valid. Catalysts would have no effect on CO_2 in the exhaust. As shown in Table 5-1, applying oxidation catalysts technology would result in a potential GHG emission reduction of, at most, 1.6 percent on a CO_2e basis.

Table 5-1 Catalytic Destruction GHG Emission Reduction

GHG	Emission Rate (tpy)	GWP	Uncontrolled CO_2e (tpy)	% Control	Controlled CO_2e (tpy)
CO_2	424,000	1	424,000	0	424,000
CH_4	145	21	3,050	40	1,830
N_2O	19.0	310	5,890	95	295
Total	--	--	433,000	--	426,000
Net Control Efficiency (1 – Controlled CO_2e / Uncontrolled CO_2e)					1.6%

7 Global CCS Institute, "Accelerating the Uptake of CCS: Industrial Use of Captured Carbon Dioxide," March 2011.
8 Wark, K. and C.F. Warner, "Air Pollution: Its Origin and Control," 2nd Edition, Harper Collins Publishers, 1981. Page 333.
9 Intergovernmental Panel on Climate Change (IPCC), "Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories," 2000. Page 188.

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Removal of NO_X Control System (SNCR)

SNCR systems convert, depending upon the reagent and furnace conditions, between 10 and 20 percent of NO_X in the exhaust to N_2O. SNCR systems do not generate any CO_2 or CH_4, so elimination of the system would not affect concentrations of these compounds in the exhaust gas. Assuming the SNCR system accounts for all of the N_2O generated by the boiler, and that removal of the SNCR system would reduce N_2O emissions to zero, the reduction in GHG emissions would be 1.4 percent on a CO_2e basis.

Table 5-2 Removal of SNCR GHG Emission Reduction

GHG	Emission Rate (tpy)	GWP	Uncontrolled CO_2e (tpy)	% Control	Controlled CO_2e (tpy)
CO_2	424,000	1	424,000	0	424,000
CH_4	145	21	3,050	0	3,050
N_2O	19.0	310	5,890	100	0
Total	--	--	433,000	--	427,000
Net Control Efficiency (1 – Controlled CO_2e / Uncontrolled CO_2e)					1.4%

Ranking GHG Control Alternatives by Effectiveness

Below is a ranking of the technically feasible GHG control alternatives, starting with the most effective, on a CO_2e basis:

- Biomass Fuel – Net reduction in atmospheric CO_2 stocks
- Carbon Capture and Sequestration – 83 percent reduction in emitted GHGs on a CO_2e basis
- Catalytic Destruction – 1.6 percent reduction in emitted GHGs on a CO_2e basis
- Removal of NO_X Control System (SNCR) – 1.4 percent reduction in emitted GHGs on a CO_2e basis
- Good Boiler Design, Good Combustion Practices, Efficient Operation – Baseline

6 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

In the March 2011 Guidance, EPA suggests that, instead of the more traditional approach where the options are considered and either eliminated or adopted in order of effectiveness, the economic, energy, and environmental impacts of all options are considered. In light of this guidance, each technically feasible option was evaluated, regardless of the Step 3 ranking.

Biomass Fuel

Over 75 percent of the fuel combusted in the proposed boiler is expected to be derived from residues generated by SPI's primary business (i.e., harvesting logs and manufacturing lumber). Use of this fuel provides an economic benefit by allowing SPI to avoid the cost of purchasing fuel to heat the on-site lumber dry kilns, purchasing electricity to power the facility, and to generate revenue by the sale of excess electricity. Similarly, an energy benefit is derived by combusting a renewable fuel instead of a fossil fuel to generate steam.

The March 2011 Guidance states that "a case-by-case analysis of the net atmospheric impact of biomass fuels would likely be prohibitively time-consuming and complex for facilities and permitting authorities." In lieu of such an analysis, the net environmental benefit described in Step 3 is realized through the combination of converting virtually all of the carbon in the fuel to CO_2, replanting harvested forest land with saplings, and sequestering the majority of the carbon harvested from forest land in produced lumber. Because of the positive economic, energy, and environmental impacts of burning biomass fuel in lieu of fossil fuels, this alternative is considered BACT for GHG emissions from the proposed boiler.

Carbon Capture and Sequestration

As discussed in Step 3, CCS systems require additional energy to remove CO_2 from the boiler flue gas, as well as to compress it for transport and storage. In the case of a biomass boiler, the concentration of CO_2 in the exhaust gas is relatively dilute (i.e., between 10 and 20 percent by weight), which would require a strong solvent to capture the CO_2, as well as a considerable amount of energy to regenerate the solvent. The additional energy required to compress the captured CO_2 to approximately 2,200 psig would necessitate increasing the energy footprint of the proposed boiler by between 40 and 60 percent, which would increase criteria and GHG emissions.

Captured and compressed CO_2 must be transported to some storage facility or end use. Storage facilities are not currently commercially available, so the only real alternative at this time is to use the CO_2 for enhance oil recovery (EOR) or use in an industrial process. There are no petroleum extraction operations or industrial processes that would be able to accept the volume of CO_2 SPI would be making available.

The economic impacts of this additional energy requirement would be in addition to the capital and operating costs associated with equipping and maintaining a CCS system.

Most cost information related to CCS technology focuses on fossil fuel (particularly coal) combustion, natural gas processing, and syngas production operations. U.S. Department of Energy analyses indicate that application of post-combustion CO_2 capture technology to a new 550 MWe net output coal-fired power plant would cost approximately \$86 per ton of CO_2 avoided.[10] A study by the Global CCS Institute estimates that cost of avoided CO_2 emitted by a pulverized coal power plant with a first-of-its-kind CCS system would range between \$62 and \$81 per tonne.[11] For comparison, the cost of naturally sourced CO_2 used for EOR is between \$10 and \$15 per tonne.[12] There is no existing or planned EOR market in the Anderson, California area, and no existing pipeline to deliver captured CO_2 to such a market; even if such a market or pipeline were available to receive CO_2 captured from the proposed cogeneration unit exhaust, the captured CO_2 could not compete with naturally-available CO_2. Based on the least expensive cost mentioned above (\$62 per tonne of CO_2 avoided) and the calculated annual CO_2 emission rate attributable to the proposed cogeneration unit, the CCS system would cost approximately \$29,000,000.

The considerable monetary and energy requirements of a CCS system suggest unacceptable economic, energy, and environmental impacts. The increased energy requirements would result in additional emissions of all pollutants other than CO_2, and, therefore, CCS systems have an unacceptable collateral environmental impact as well. As a result, CCS systems are removed from consideration as BACT for GHGs emitted by the proposed boiler.

Catalytic Destruction

Because this alternative reduces emissions of GHGs other than CO_2, the cost effectiveness was calculated on a CO_2e basis. Catalytic oxidation was estimated to reduce GHG emission by less than 6,000 tons per year. To be considered cost effective, and assuming the cost-effectiveness threshold of \$7 per ton proposed in Section 1.3.2, the annual cost would have to be less than \$42,000 annually, which is unlikely, based on the costs of catalytic systems used to reduce criteria pollutants. The economic analysis provided in the criteria pollutant BACT analysis for a catalytic oxidation system to reduce CO and VOC emissions indicated that the economic impact of these systems, due to uncertainties regarding the reliability and cost of the systems, would be unacceptable. Because the GHG reduction associated with these systems (on a percent basis) is less than the expected reduction in CO and VOC associated with an oxidation catalyst system, and the cost-effectiveness threshold for GHGs is lower than what is typical for CO and VOC, this alternative is considered to have unacceptably high collateral economic impacts, and is removed from consideration as BACT for GHG emissions from the proposed boiler.

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10 National Energy Technology Laboratory (NETL), "Cost and Performance Baseline for Fossil Energy Plants – Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 2," November 2010. DOE/NETL-2010/1397. Page 300.

11 Global CCS Institute, "Economic Assessment of Carbon Capture and Storage Technologies," 2011.

12 NETL, "Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution," March 2010.

Removal of NO_X Control System (SNCR)

Elimination of the SNCR system used to reduce NO_X emissions from the boiler would result in an increase in NO_X emissions. Because the criteria pollutant BACT analysis associated with the submitted PSD permit application proposed SNCR as BACT for NO_X emissions from the boiler, elimination of the SNCR system would result in unacceptable NO_X emissions from the boiler, and is therefore not an acceptable alternative for GHG BACT based on unacceptable collateral environmental impacts, and are removed from consideration as BACT for GHG emissions from the proposed boiler.

Good Boiler Design, Good Combustion Practices, Efficient Operation

For the proposed biomass-fired cogeneration unit, utilizing good boiler design, and then operating the boiler efficiently and with good combustion practices are the control alternatives that SPI proposes as BACT for the project. As stated previously, these options are considered the baseline for the BACT analysis, and all other options were considered to be applied over and above these options. Each of these options have a positive energy and environmental, and most likely economic, impact, and are considered to be BACT for GHG emissions from the proposed boiler.

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7 Step 5 – Selection of BACT

Based on the analysis presented here, SPI proposes that BACT for GHGs from biomass-fired boilers is the exclusive use of biomass fuel (aside from natural gas use during startup and for flame stabilization), good boiler design, proper combustion practices, and efficient operation. For the cogeneration unit, SPI proposes an annual GHG BACT limit of 433,000 tpy CO_2e, or 0.36 lb CO_2e per lb steam (900 °F, 1,250 psig), on a 12-month block average basis.

For comparison, Table 7-1 summarizes the GHG BACT limits in the permits of the facilities listed in Table 2-3.

Table 7-1. Summary of GHG BACT Limits for Biomass-Fired Boilers in RBLC

Facility	GHG Limit	GHG Limit Units	GHG Limit Averaging Period
North Springfield Sustainable Energy Project	15,564[1]	Btu/kWh (gross)	12-month rolling average
Beaver Wood Energy Fair Haven LLC	2,993	lb CO_2e/MWh	30-day rolling avg
WE Energies – Rothschild	2,675[2]	lb CO_2e/MWh (net)	12-month rolling average
Abengoa Bioenergy Biomass of Kansas LLC	3,050	lb CO_2e/MWh (gross)	12-month rolling average
Montville Power LLC	0.34	lb CO_2e/lb steam produced	30-day rolling avg

1 Annual limit of 590,109 CO_2e/yr. Includes biomass, natural gas, and diesel fuel combustion, as well as SF_6 from switchgear. Roughly equivalent to 3,208 lb CO_2e/MWh (net).

2 Phased in: first two years of operation, limits is 2,668 lb CO_2e/MWh (net electrical output)

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8 Reciprocating Internal Combustion Engines

The proposed facility design includes a natural gas-fired emergency boiler feedwater pump, that would be used if the cogeneration unit had to be shut down when power from the grid was unavailable. Planned operation for this piece of emergency equipment will be restricted to testing and maintenance (i.e., a maximum of 100 hours per year).

8.1 Step 1 – Identify Available Control Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies.

The purpose of the emergency boiler feedwater pump is to provide a quickly deployable source of power that will be available when electrical power from grid is not available to operate the electric motors that power the feedwater pumps that would be relied upon to circulate water through the boiler during a normal shutdown process. Natural gas is considered the fossil fuel that generates the least GHG emissions per unit of energy produced. The only real alternative to a natural gas-fired pump is a diesel-fired pump, and diesel fuel is less desirable from a GHG emission perspective. For this reason, no alternative processes or fuels are considered for this analysis. However, within the category of reliable natural gas-fired engines that provide sufficient power for the assigned task, use of the most efficient model available will result in the least GHG emissions.

GHG-reducing add-on technology exists (e.g., carbon capture and storage), and has been discussed at length elsewhere in this document. Because the pump must be available quickly and reliably, an add-on control that complicates operation and potentially reduces engine readiness, compromises the emergency role of the engine, and is therefore unacceptable for consideration as GHG-reducing technology for the proposed emergency natural gas-fired engine.

8.2 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

Use of the most efficient commercially available natural-gas fired engine that is capable of reliably operating an appropriate boiler feedwater pump in a timely manner is a technically feasible means of limiting GHG emissions from the emergency natural gas-fired engines.

8.3 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility, are ranked, starting with the most effective.

The only alternative considered is the use of the most efficient commercially available, natural gas-fired engine that does not compromise the availability and rapid deployment of the boiler feedwater pump for emergency duty.

8.4 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

Because only one alternative is considered, there is no opportunity to compare and contrast the collateral impacts of competing technologies.

8.5 Step 5 – Selection of BACT

Based on the analysis presented here, SPI proposes that BACT for GHGs from the natural gas-fired engine used to power the emergency boiler feedwater pump is the use of the most efficient commercially-available engine capable of providing reliable and timely operation to fulfill the assigned emergency role.